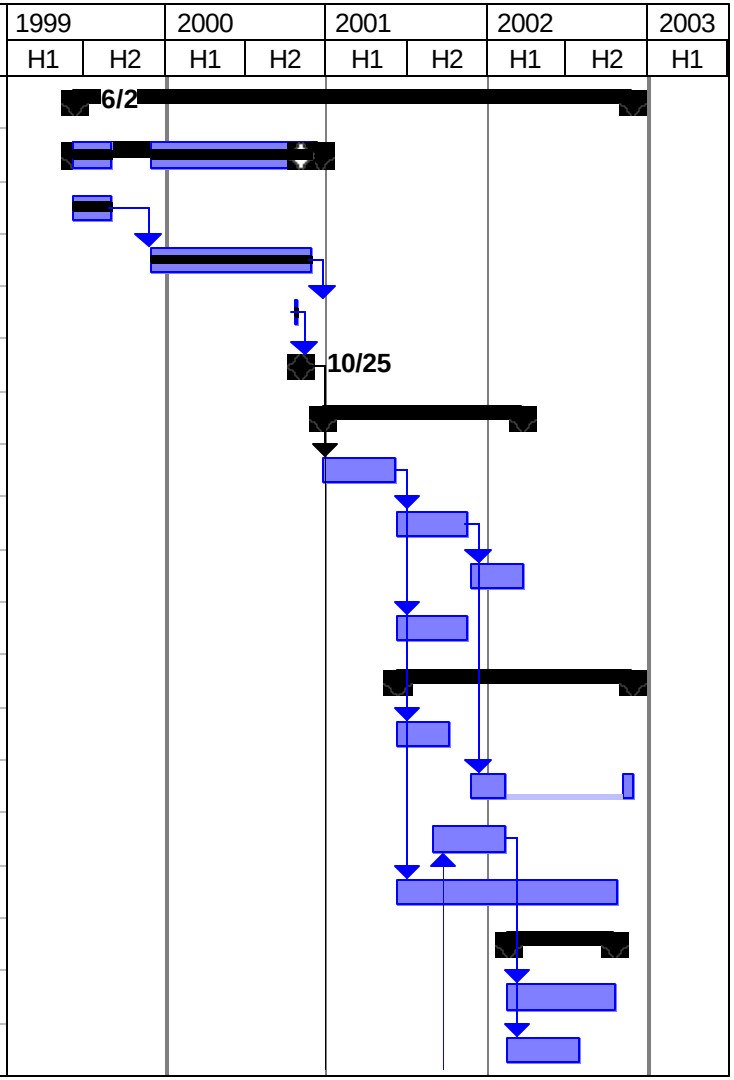
Reclamation's Post 2004 Operations Options Analysis

Options Work Group

Restructuring Plan Timeline

ID	Task Name	Duration	Start
1	**Restrucuturing Plan**	**913 days**	**Wed 6/2/99**
2	**Element 1 (Operational Options Sel**	**403 days**	**Wed 6/2/99**
3	Develop Options	61 days	Wed 6/2/99
4	Analyze Options	263 days	Sun 11/21/99
5	Prioritize Options	1 day	Sun 10/15/00
6	Recommend Option to MP Manag	12 days	Wed 10/25/00
7	**Element 2 (Procedure Development**	**330 days**	**Mon 12/18/00**
8	CAISO Procedures	120 days	Mon 12/18/00
9	Western Procedures	120 days	Mon 6/4/01
10	Water Customer Schedules	90 days	Mon 11/19/01
11	F&WS Procedures	120 days	Mon 6/4/01
12	**Element 3 (Interagency Coordinatio**	**390 days**	**Mon 6/4/01**
13	CAISO Interconnection Agreemen	90 days	Mon 6/4/01
14	Western COMA modification	81 days	Mon 11/19/01
15	Western O&M Cost Suballocaiton	120 days	Mon 8/27/01
16	F&WS Agreement	365 days	Mon 6/4/01
17	**Element 4 (Rate Setting Adjustments**	**180 days**	**Mon 2/11/02**
18	Water Rate Adjustments	180 days	Mon 2/11/02
19	Power Rate Setting Adjustments	120 days	Mon 2/11/02



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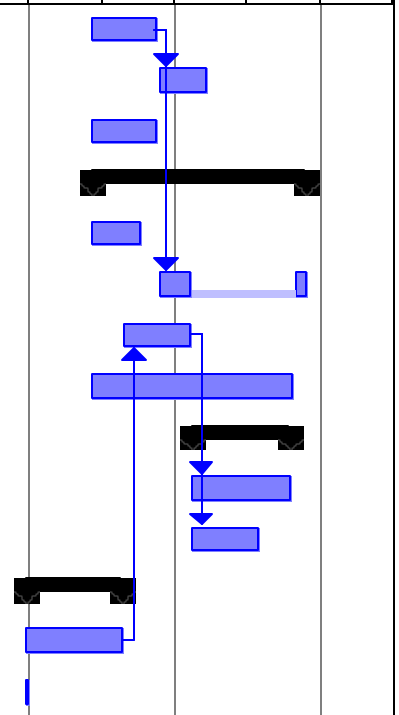


Post 2004 Operations

- Increased costs are predicted due to expiration of PG&E Integration Contract and need to interface with ISO
- PG&E Contract covers all CVP loads, allows monthly accounting of energy, and PG&E to schedule CVP power plants hourly patterns.

Post 2004 Operations

- ISO interface will mean CVP must pay what others are currently paying.
- ISO interface will mean more information will need to be developed for the CVP and provided to ISO on a more frequent level.

Post 2004 Operations

- CVP Generation and Pumping loads are not hourly coincident.
- ISO requires balanced hourly schedules.
- Hourly imbalances are expected to be assessed at the market clearing price.
- Pumping must be scheduled hourly and daily.
- There are over 200 pumping plants in the CVP that must be served under a scheduled.

Post 2004 Operations Options
Preliminary Analysis

- Annual impacts from hourly imbalances initially estimated from $700k to over $4.5 million.
- If the generation would have been rescheduled to eliminate the imbalance, the pumping costs would still range from an additional $50k to $1.6 million annually.

Post 2004 Operations

- Electric Industry Restructuring will mean more work on both the Water and Power customers, Western, and Reclamation.
- Electric Industry Restructuring will require new equipment for interface and accounting.
- It can provide an opportunity for improvement
- Increasing the value of generation can be used to offset some of the increased costs.

Post 2004 Operations

- Need to identify how value can be improved.
- Work with CVP Water and power customers to
  - develop improvement options.
  - Evaluate the options
  - Help in prioritizing the options

Post 2004
Operations Work Group
Goal

- Work Group Tasks
  - Develop Operational Options
  - Analyze Options
  - Develop Prioritization Criteria
  - Rank Options using Criteria

Post 2004
Operations Work Group
Goal

- Work Group Tasks
  - Develop Operational Options
    - Integration Contract (No Change)
    - Pump Following (kWh reservation for pumping)
    - Max Peaking (PU reservation retained by allocation)

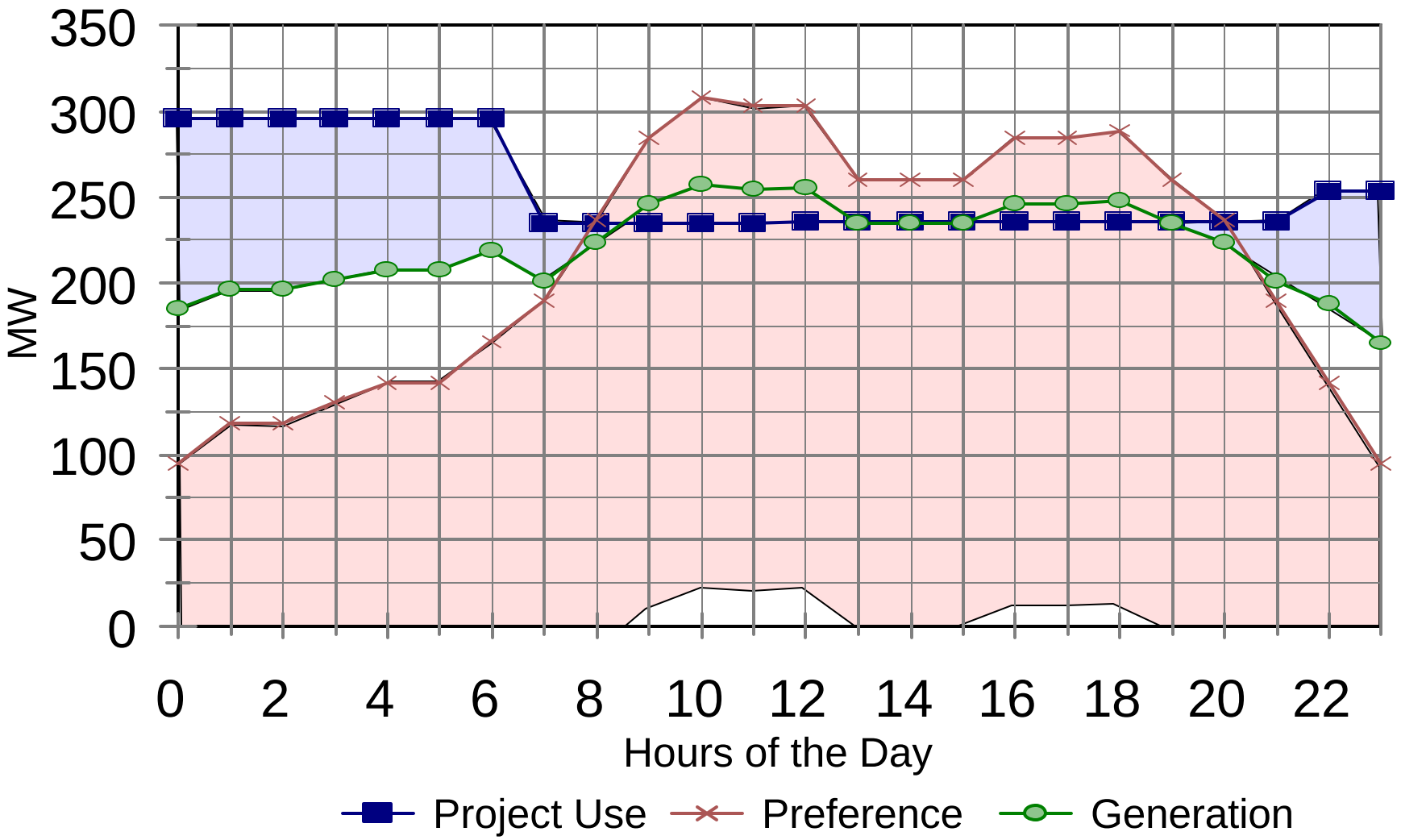
CHART IS FOR OPTION EXAMPLE ONLY

Purchases for Project-Use

Option 1 Integration Contract

Comparison Post 2004 Operations

Purchases for Preference Loads



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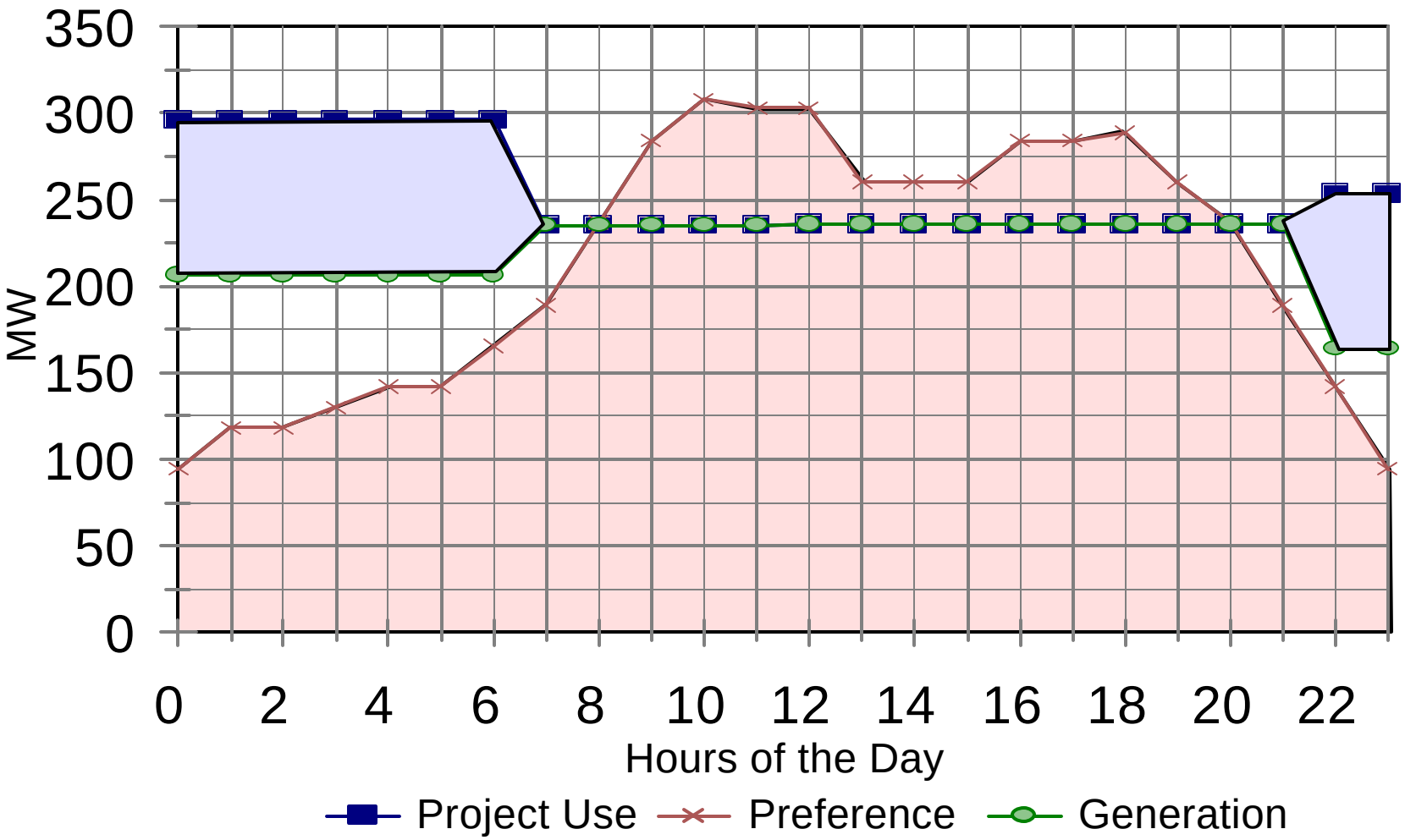
Purchases for Project-Use

Option 2 Pump Load Following

Comparison Post 2004 Operations

Purchases for Preference Loads



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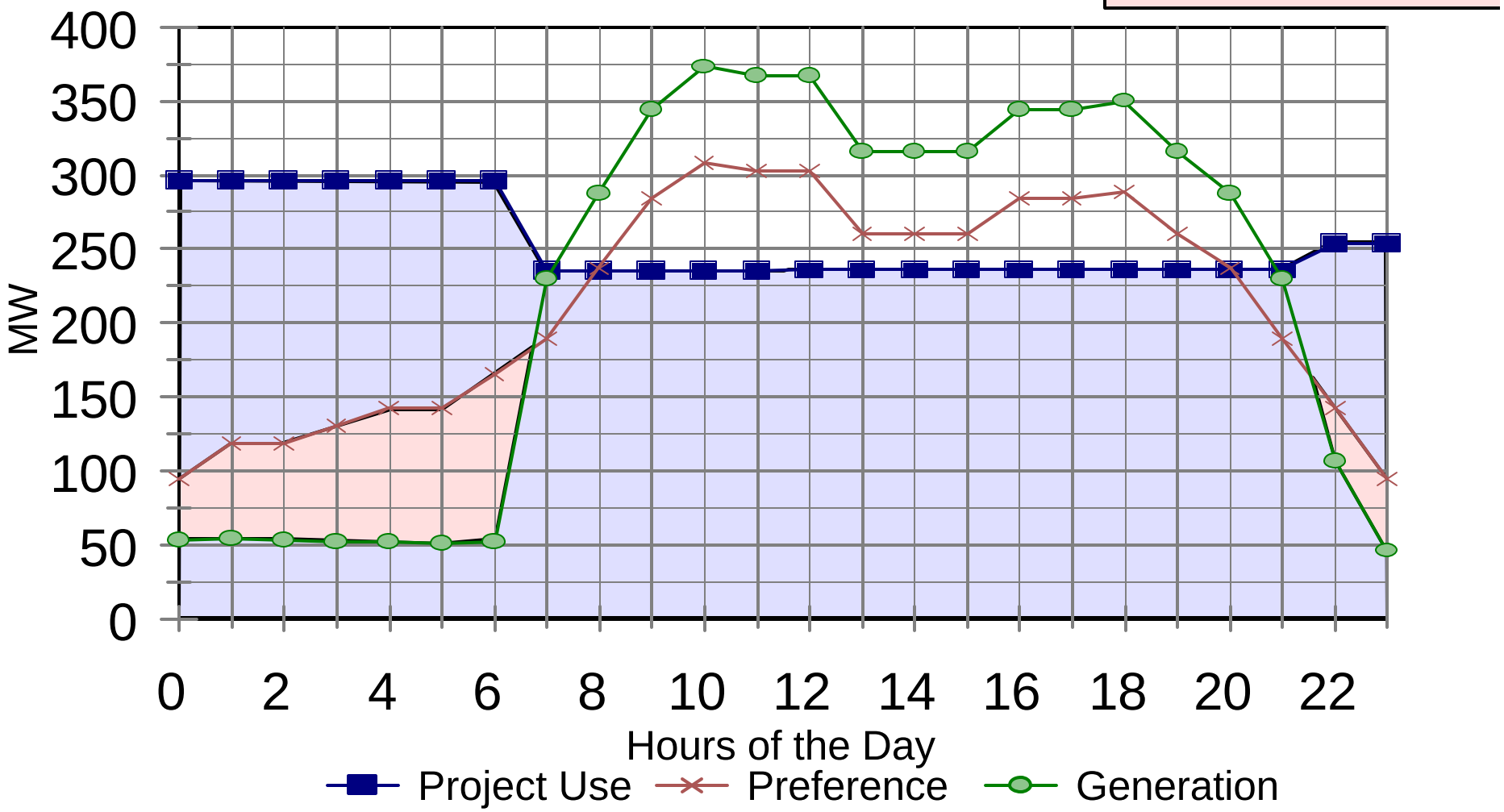
Purchases for Project-Use

Option 3 Max Peaking Generation

Comparison Post 2004 Operations

Purchases for Preference Loads



Post 2004
Operations Work Group
Goal

- Work Group Tasks
  - Develop Operational Options
  - Analyze Options
    - Operational Costs
    - Implementation Costs
    - Operation Flexibility

Post 2004
Operations Work Group
Goal

- Work Group Tasks
  - Develop Operational Options
  - Analyze Options
  - Develop Prioritization Criteria
    - Develop Objectives
    - Develop Decision Matrix
    - Develop Weighting values

Post 2004
Operations Work Group
Goal

- Work Group Tasks
  - Develop Operational Options
  - Analyze Options
  - Develop Prioritization Criteria
  - Rank Options using Criteria
    - Normalize Cost components for each options
    - Apply ranking method

Post 2004 Operations

- Options are prioritized with a Matrix.
- Use of a Matrix allows impartial prioritization.
- Ensures objectives are met
  - Maximize Benefits.
  - Lowered Administrative Costs.
  - Maximum additional operational flexibility to meet environmental constraints.

Prioritization Matrix for Options Scenarios

Priority Matrix **Category**	**weighing factor** 1	**weighing factor** 2	**weighing factor** 3
1 **Net Benefits of Resources/Loads**	Option is in upper third of normalized net benefits.	Option is in middle third of normalized net benefits.	Option is in lower third of normalized net benefits.
2 **Agency Additional Administrative Cost**	Option is in lower third of normalized costs.	Option is in middle third of normalized costs.	Option is in Upper third of normalized costs.
3 **Operational Flexibility**	Option provides additional operational flexibility to meet environmental objectives.	Option provides no additional operational flexibility to meet environmental objectives.	Option reduces operational flexibility to meet environmental objectives.

Use of Matrix. Priority number determined by multiplying the category number by weighing factor for each category and adding the results. The lowest value would have the highest preference.

Post 2004
Operations Work Group
Goal

- Work Group Tasks
  - Develop Operational Options
  - Analyze Options
    - Operational Costs
      - Develop Model of the CVP for Post 2004
      - Develop Market Conditions
      - “Operate” the CVP for Value

Daily Generation and Hourly Pumping Pattern Development

- Products needed for Options analysis
  - Generation: Daily generation releases shaped to hourly pattern depending upon Option.
  - Pumping: Pattern is an hourly pattern and varies with hydrology.
  - Price Curve based upon the latest market data.

Daily Generation and Hourly Pumping Pattern Development

- No computer model currently exists that creates an hourly pump pattern.
- Pattern selected should reflect expected operations.
- Primary assumption - For a given amount of water pumped in a month at a facility, the hourly pumping pattern will be the same for that facility.

Daily Generation and Hourly Pumping Pattern Development

- **Approach to pattern development-**
  - **Model the monthly CVP Operation for Generation and Pumping**
  - **Create a monthly pattern from the model results. Normalizing to yearly value.**
  - **Extract actual monthly operational data for the CVP from hourly logs.**
  - **Create a monthly pattern from the Operational data.**
  - **Superimpose the monthly patterns and select the closest match.**
  - **Proportion the daily generation and hourly pumping operational pattern to the monthly model data.**

Generation and Pump Model

- Generation and Pumping pattern should reflect the same hydrological conditions.
- Hydrological conditions and environmental assumptions need to be modeled.
- Only Model that has relevant data is the Draft PEIS Preferred Alternative PROSIM run.

Generation and Pump Model Data Base Pattern

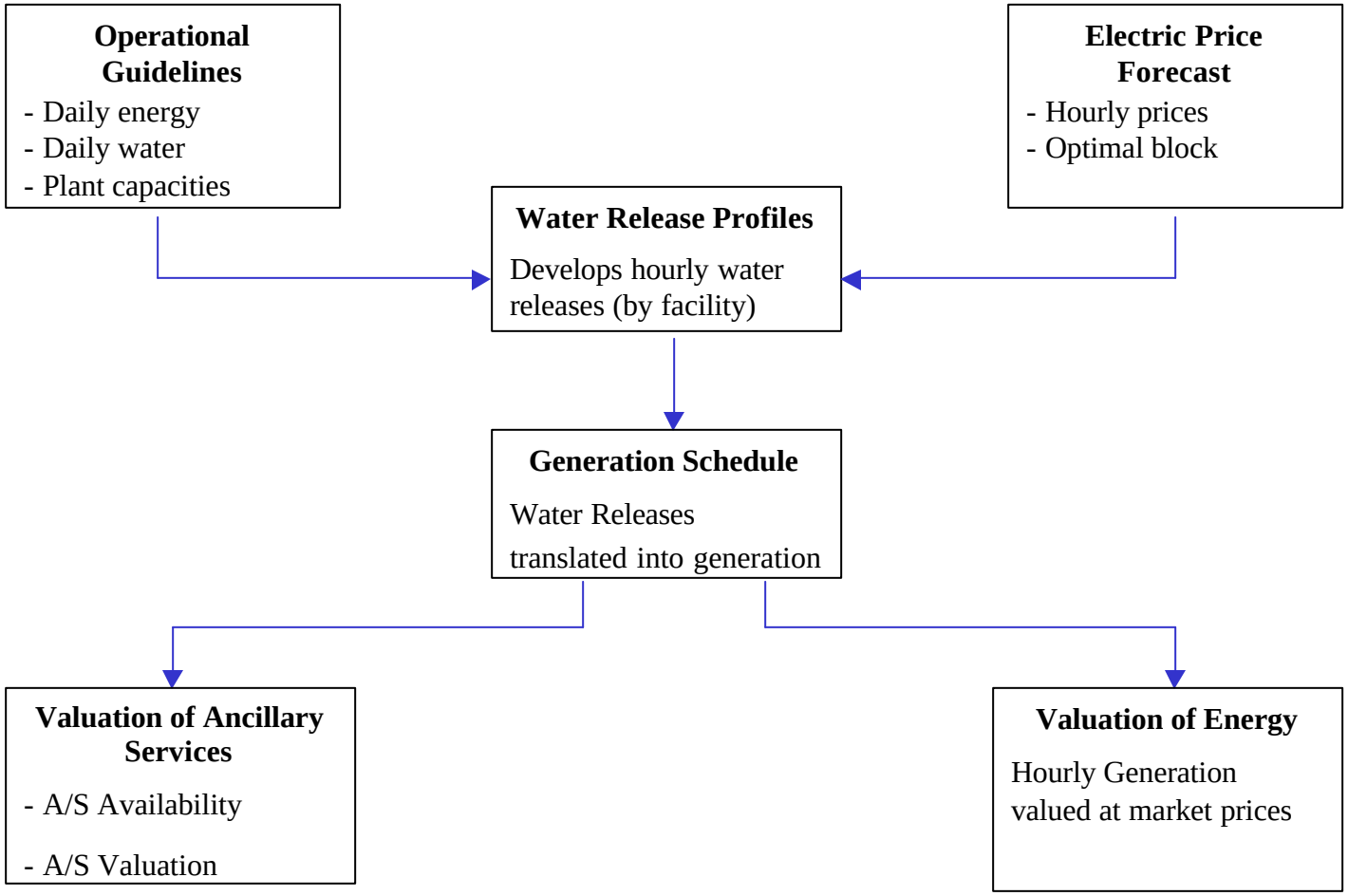
- Snap shots taken from the PROSIM run to represent a “reasonable” range of conditions.
- Range of conditions are not expected to change the results of analysis for any one Option.
- Range to represent dry, normal, and wet type of condition.

Generation and Pump Model Data Base Pattern

- Condition criteria used reflect current OCAP criteria which uses Sacramento River Index.
- Sacramento River Index (SRI) is the annual unimpaired inflow of the Sacramento, Feather, Yuba, and American Rivers.
- Model data was Ranked by SRI.
- Dry condition chosen as 90% exceedance.
- Wet as 10% exceedance.
- Normal as the SRI median between 90 and 10%.

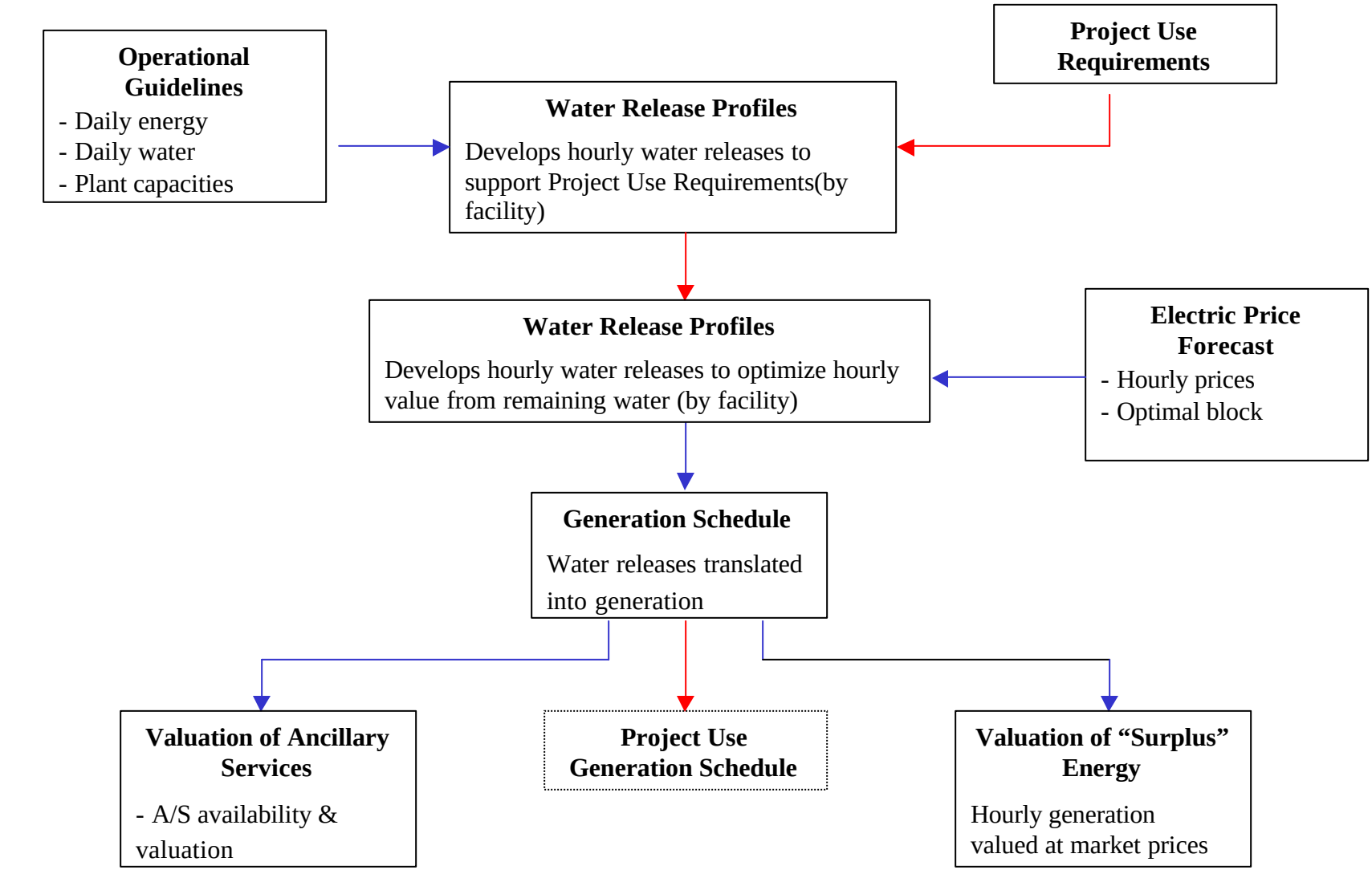
Flow Chart of Model Analysis

"Maximum-Peaking Alternative"

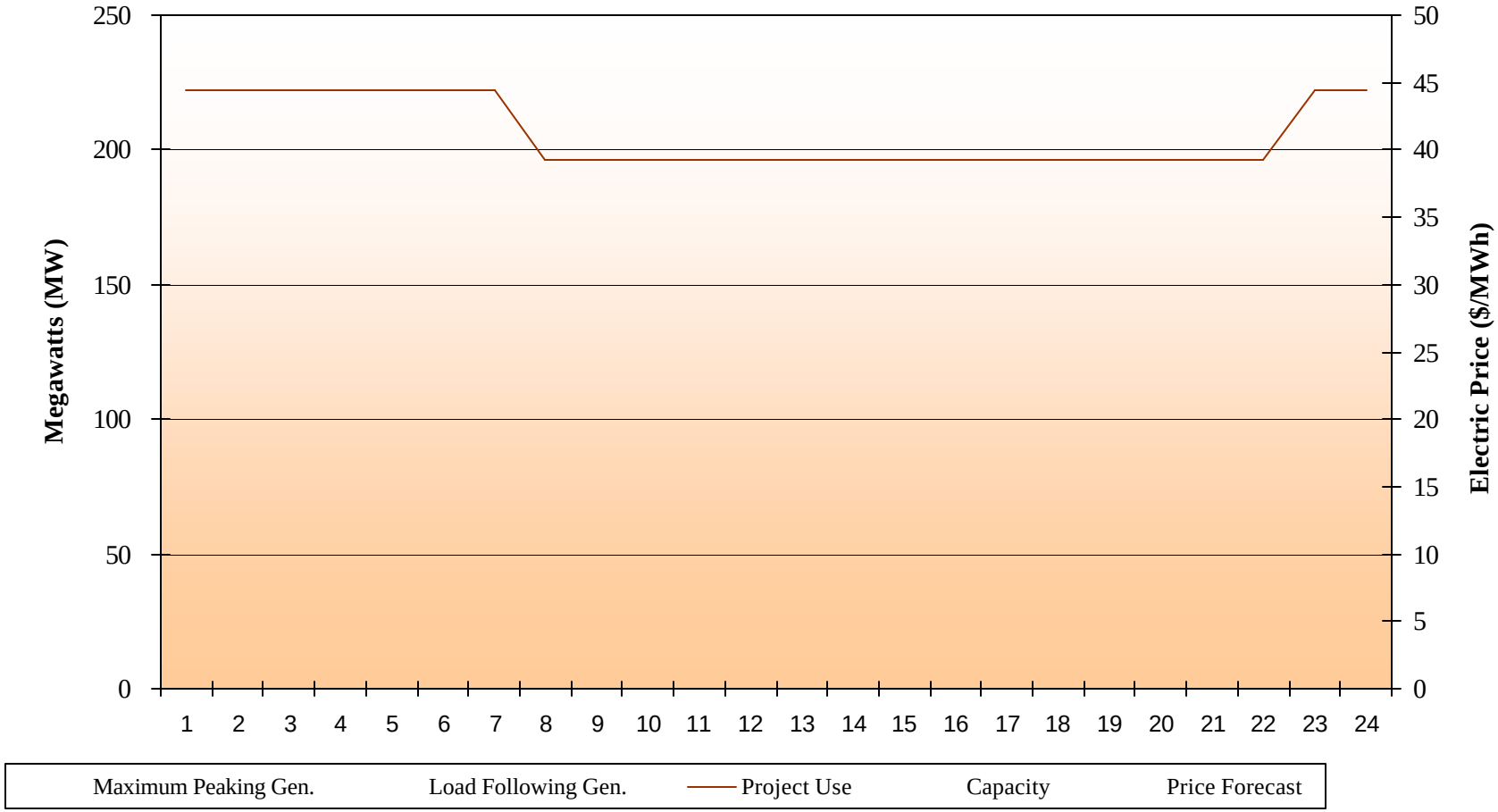


Flow Chart of Model Analysis

"Load-Following Alternative"



Options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Megawatts (MW)
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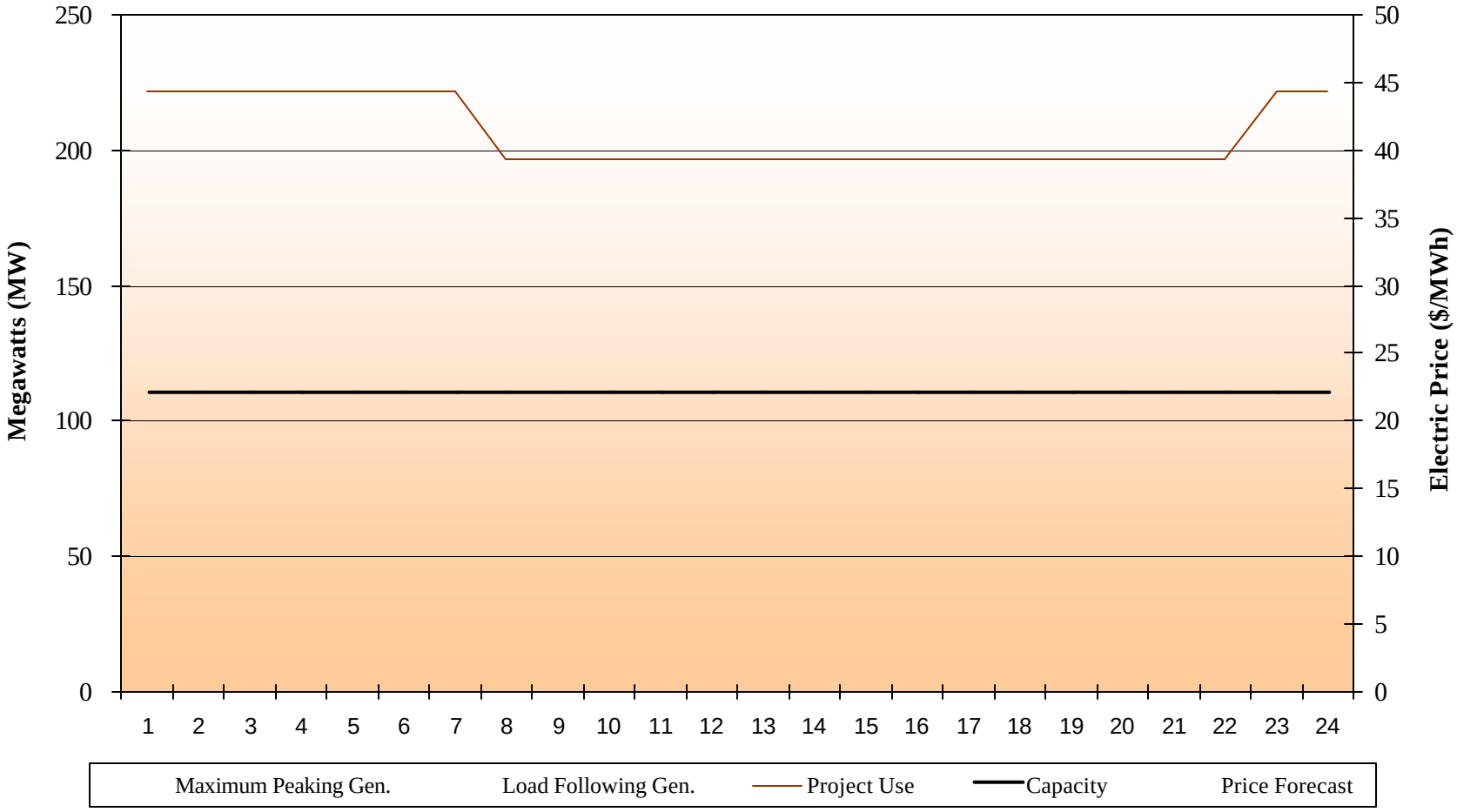
Electric Price ($/MWh)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Maximum Peaking Gen.
Load Following Gen.
Project Use
Capacity
Price Forecast

Options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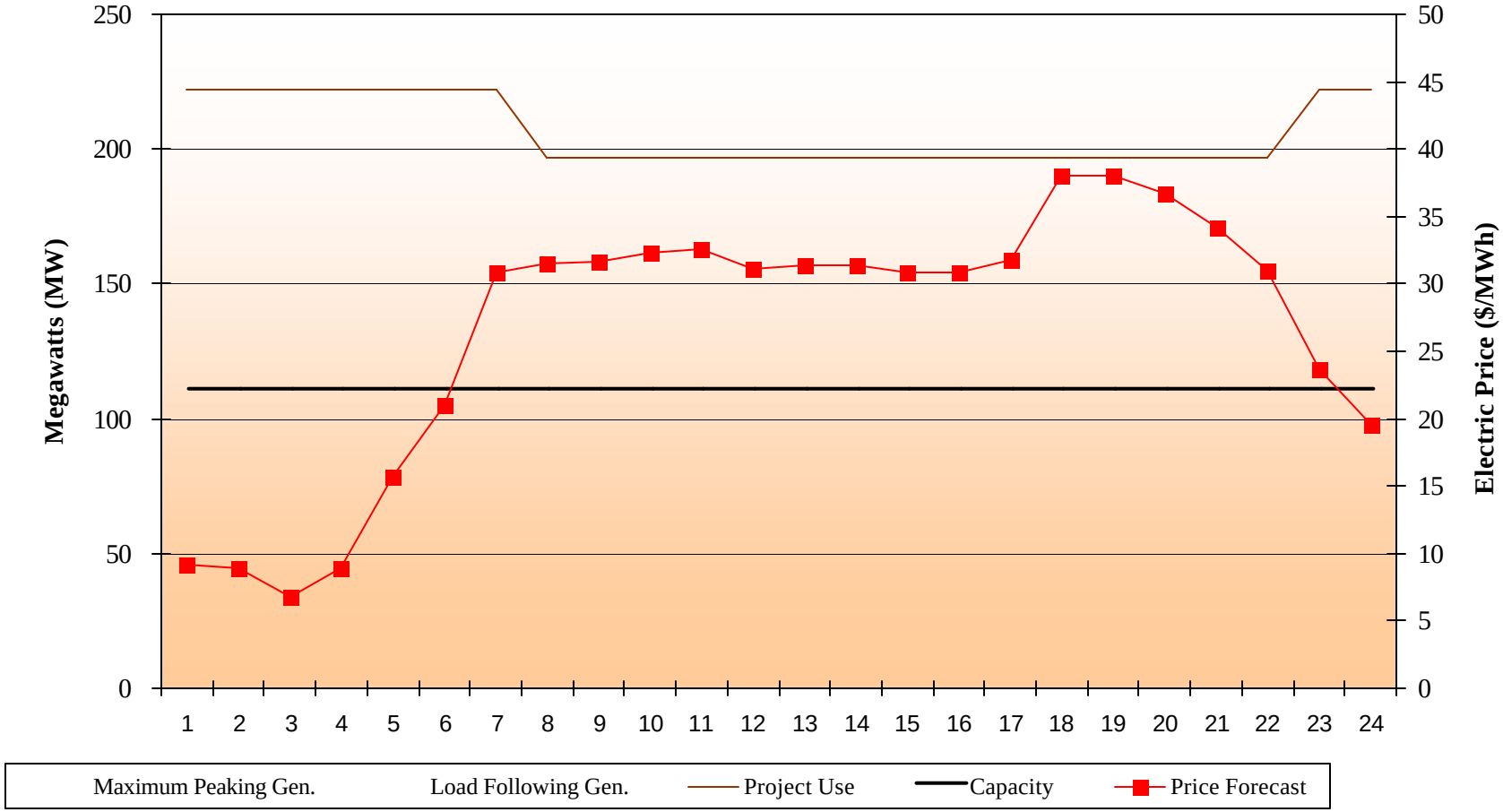
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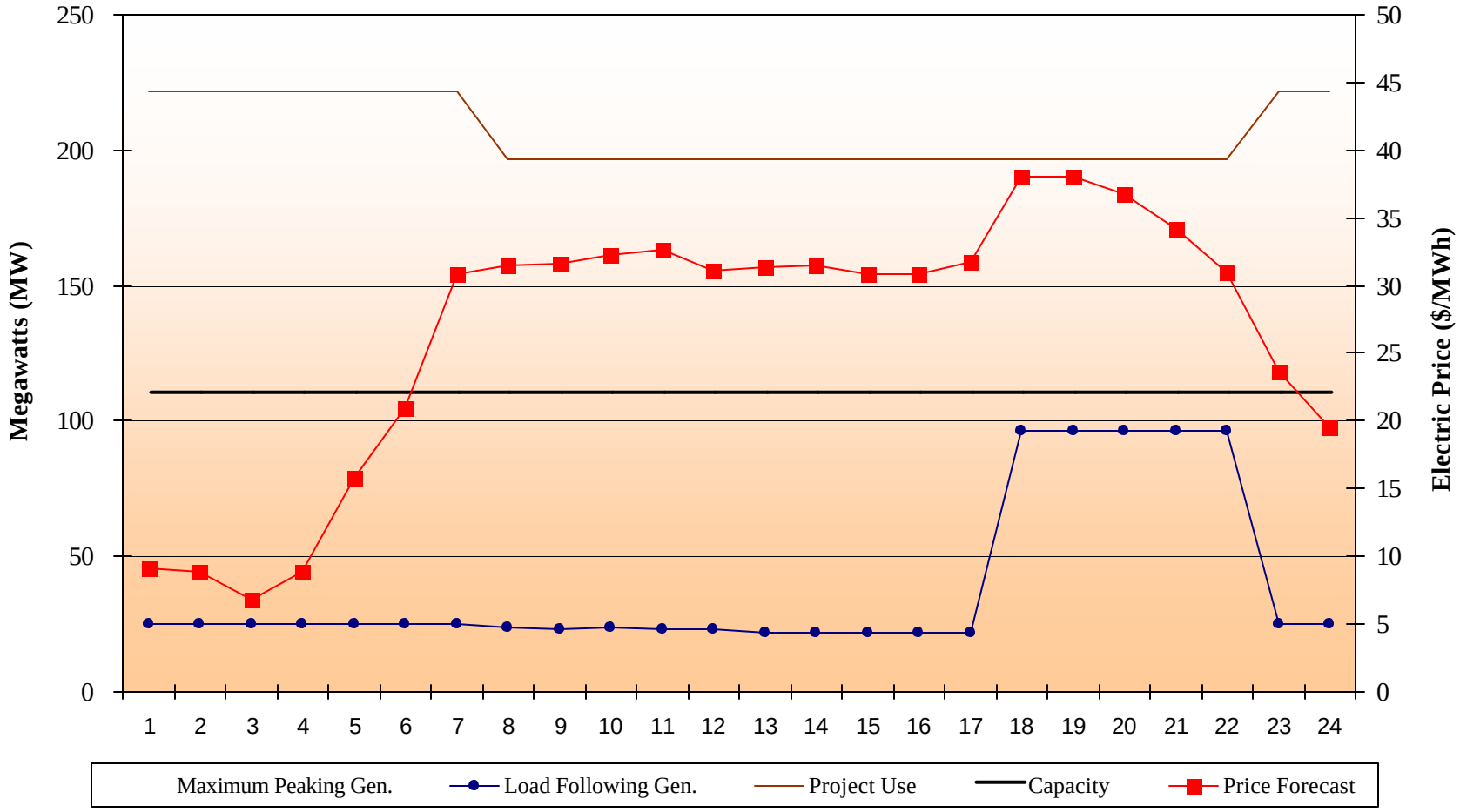
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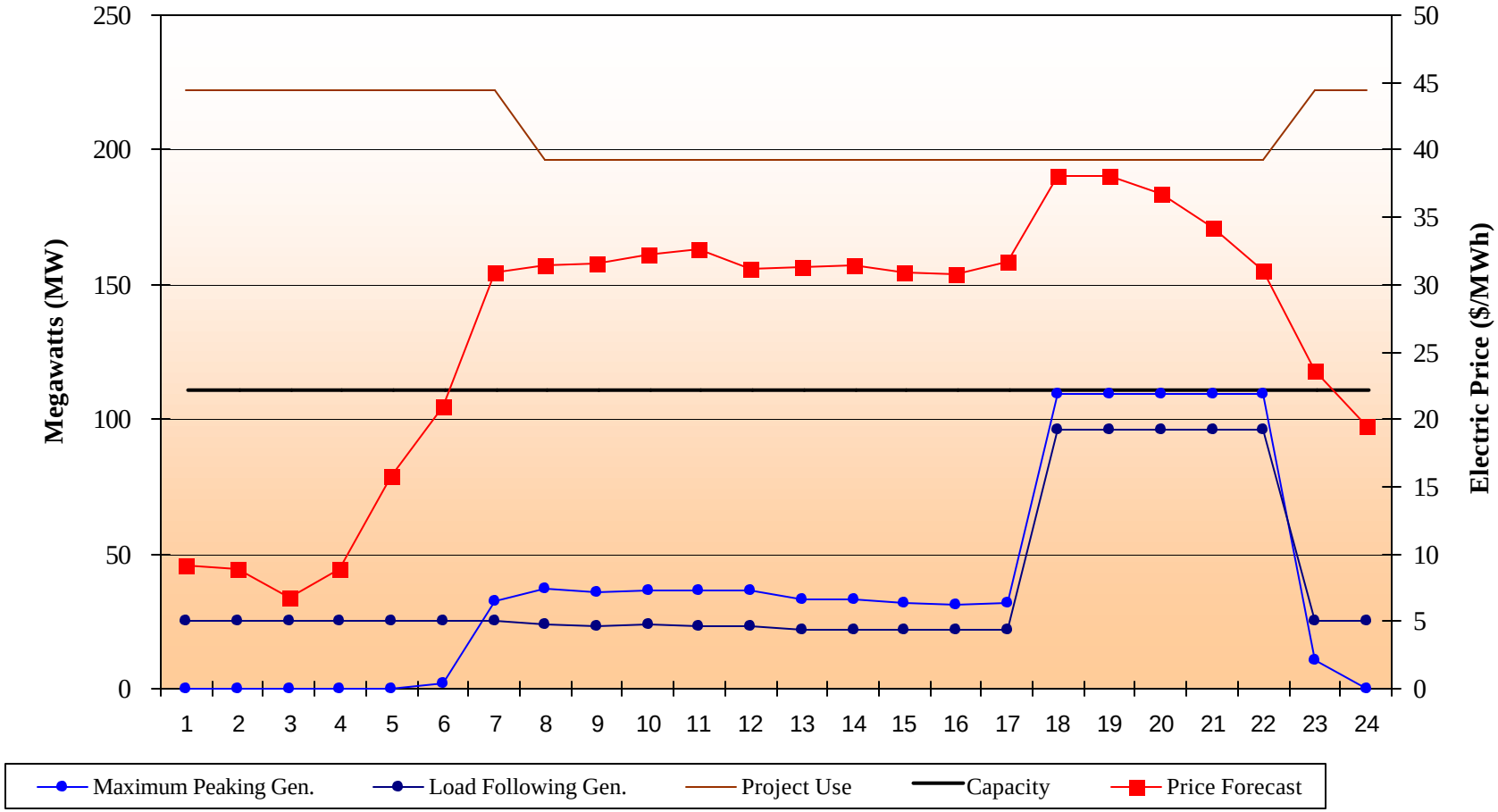
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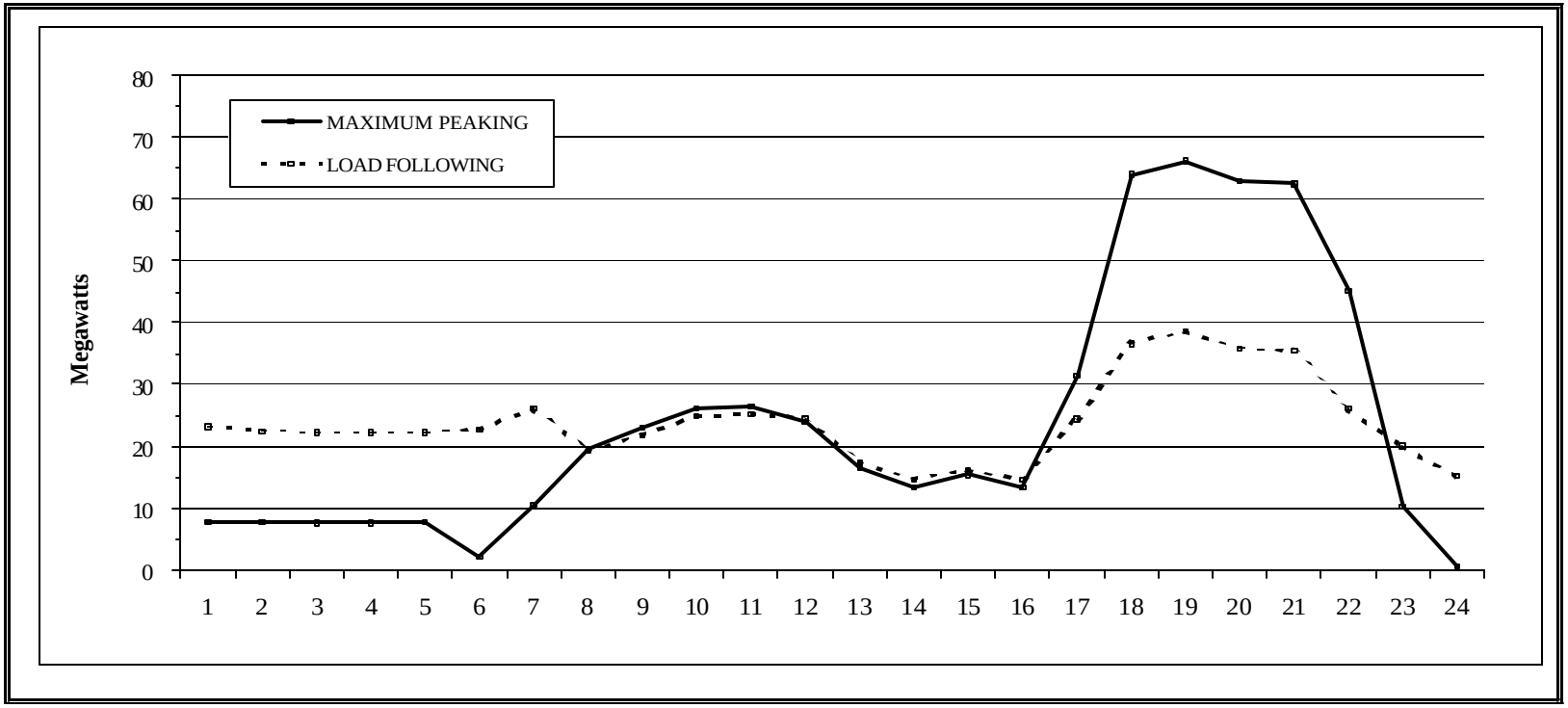
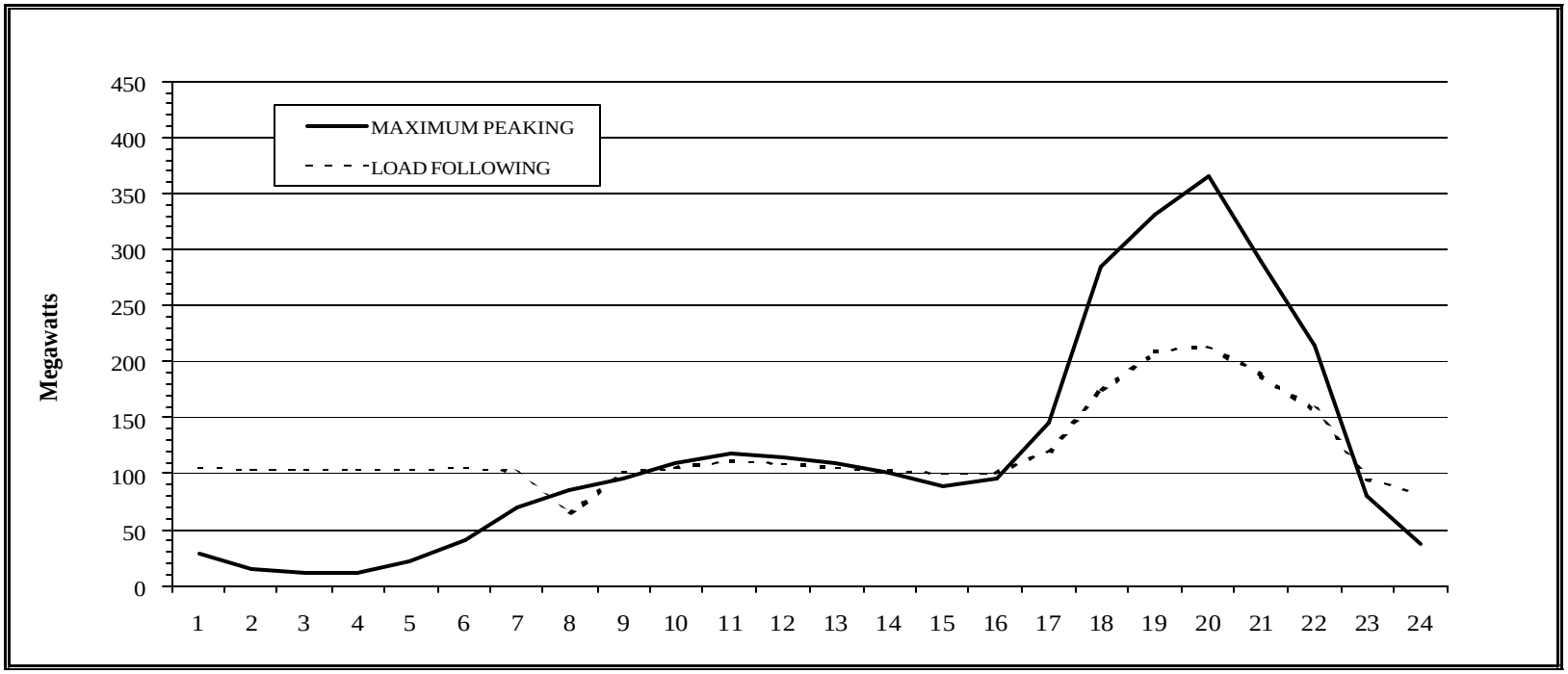
Samples of Analysis

GENERATION SCHEDULES FOR TRINITY
LOAD FOLLOWING VERSUS MAXIMUM PEAKING
MEDIAN-YEAR WATER CONDITIONS
(JANUARY)



Samples of Analysis

GENERATION SCHEDULES FOR SHASTA
LOAD FOLLOWING VERSUS MAXIMUM PEAKING
MEDIAN-YEAR WATER CONDITIONS
(MARCH)



Operational Analysis Summary

	Wet Year		Median		Dry	
	Max Peaking	Load Following	Max Peaking	Load Following	Max Peaking	Load Following
Generation Value	$279,950,000	$244,523,000	$233,658,000	$184,929,000	$151,979,000	$130,497,000
Pumping Support Cost	$33,699,000	**$140,000**	$46,098,000	**$181,000**	$23,939,000	**$4,542,000**
Net Value	$246,251,000	$244,383,000	$187,561,000	$184,747,000	$128,040,000	$125,955,000
difference	**$1,868,000**		**$2,814,000**		**$2,085,000**	

Sensitivity

SHASTA OPERATIONS
LOAD FOLLOWING AND MAXIMUM PEAKING OPERATIONS
SENSITIVITY ANALYSIS OF "ON-PEAK" AND "OFF-PEAK" PRICE VOLATILITY
MEDIAN-YEAR WATER CONDITIONS - MARCH 2005

	NET VALUE			% CHANGE
CATEGORY	Maximum Peaking	Load Following	VARIANCE (MP-LF)	IN VALUE
Modeled	830,644	579,742	250,902	
5% Increase in "On-Peak" Prices	886,782	607,892	278,890	11%
10% Increase in "On-Peak" Prices	942,920	636,043	306,877	22%
15% Increase in "On-Peak" Prices	999,059	664,193	334,866	33%
20% Increase in "On-Peak" Prices	1,055,197	692,343	362,854	45%

Options Work Group Administrative Costs

- Western and Reclamation existing staffing level studied.
- Both agencies hardware infrastructure assessed.
- Changes to staffing and hardware determined based upon generic industry configuration
- No Third Party costs to agencies analyzed.

Administrative Cost Analysis

OPTION	NON-RECURRING COSTS	ANNUAL COSTS	NORMALIZED COSTS
Load Following with third party as Scheduling Coordinator	$3,700	$405,000	17.5%
Load Following with Western as Scheduling Coordinator	$63,700	$405,000	20.1%
Load Following with Reclamation as Scheduling Coordinator	$373,700	$1,957,500	100%
Maximum Peaking with third party as Scheduling Coordinator	$3,700	$405,000	17.5%
Maximum Peaking with Western as Scheduling Coordinator	$60,000	$405,000	19.9%
Maximum Peaking with Reclamation as Scheduling Coordinator	$373,700	$1,957,500	100%

Option Analysis Preliminary Summary

OPTION	1 Net Benefits of Resources/Loads	2 Agency Additional Administrative Cost	3 Operational Flexibility	Prioritization Factor
Load Following with third party as Scheduling Coordinator	**2**	**1**	**2**	**10**
Load Following with Western as Scheduling Coordinator	**2**	**1**	**2**	**10**
Load Following with Reclamation as Scheduling Coordinator	**2**	**3**	**2**	**14**
Maximum Peaking with third party as Scheduling Coordinator	**2**	**1**	**1**	**7**
Maximum Peaking with Western as Scheduling Coordinator	**2**	**1**	**1**	**7**
Maximum Peaking with Reclamation as Scheduling Coordinator	**2**	**3**	**1**	**11**

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